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Costs of Coal and Electric Power Production—The Impact of Environmental Control Technologies for Coal-Cleaning Plants

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COSTS OF COAL AND ELECTRIC POWER PRODUCTION— THE IMPACT OF ENVIRONMENTAL CONTROL TECHNOLOGIES FOR COAL-CLEANING PLANTS

by

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ABSTRACT

Costs of 10 alternative environmental control technologies were calculated for three hypothetical and three actual cleaning plants. The cost of lime-limestone slurry coating ranged from $0.22 to $0.50 per ton of product coal. For one actual plant cleaning high-sulfur coal, the range of costs for the 10 alternatives was from $0.076 to $9.89 per ton of product coal, based on March 1978 costs. For the purpose of supplying electric utility customers, coal cleaning reduces the cost of meeting environmental standards because it is less expensive (potentially) to control the water pollution from the coal-cleaning plant than the air pollution from the utility power plant. Applying the less expensive environmental control technology options to coal-cleaning wastes adds approximately 0.2 to 0.4 mills/kWh to the costs of electric power production (1979 costs).

INTRODUCTION

The single most important use of coal in the United States is electric power generation. This is expected to increase dramatically in the next decade as utility usage of liquid and gaseous fuels is reduced because of high costs and shortages of petroleum and natural gas.

It is in the interest of the general public to provide environmental safeguards at minimum expenditure of human, monetary, and natural resources, including energy resources. The use of the presently abundant energy source, bituminous coal, requires safeguards against atmospheric emissions of sulfur dioxide arising from combustion of both organic sulfur and pyritic sulfur in the coal. Cleaning of stack gases from coal-burning plants for removal of sulfur dioxide is expensive and presents problems in disposal of the byproduct sulfur or sulfuric acid. Cleaning of the coal prior to shipment to the consuming plant reduces the sulfur in the coal and thus the cost of environmental control at the consuming plant. However, the waste from coal cleaning contains active materials that dissolve in water, so that environmental safeguards for protection of the water environment must also be provided at the cleaning plant. Thus, pollution has been moved from one location to another, and changed in type, but it still must be controlled. This report addresses some of the economic issues of moving the location and type of pollution connected with the pyritic sulfur in coal from the power plant to the cleaning plant.

Research at Los Alamos Scientific Laboratory (LASL) into the environmental chemistry of coal

wastes has demonstrated the quantitative chemical relationships between the composition of a waste and the contaminants to be found in water that has been in contact with the waste. We have examined several alternative environmental control technologies (ECTs) aimed at reducing contaminants to an acceptable level before surface or ground waters can pass beyond the boundaries of a given coal mining/cleaning operation. Preliminary cost comparisons of some of these environmental control technologies for coal-cleaning wastes are reported elsewhere.[1,2]

Cleaning of raw coal removes both inert ash and reactive sulfur-bearing minerals. The greater the depth of cleaning, the greater the cost of the cleaning plant operation, and also the greater the cost of waste disposal, including any environmental control cost. Up to a point, however, the greater the depth of cleaning, the less the costs to the electric utility for ash disposal and for flue gas desulfurization (FGD). Therefore, in evaluating the economics of alternative ECTs for coal-cleaning waste, consideration should be given to their relation to the ECT costs of the customer electric utilities. The objective is to achieve a minimum joint ECT cost, which is passed on to the ultimate consumer of the electrical energy.

In January 1978 the Department of Energy (DOE) published a report prepared by the Hoffman-Muntner Corporation giving 12 very detailed cost studies based on hypothetical mine-utility combinations.[3] These cost studies were funded by the US Environmental Protection Agency (EPA) as part of the Coal Preparation Research portion of the Interagency Energy-Environment Research and Development Program. Each case compared the cost of meeting utility boiler emission standards for SO_2 by FGD alone with the cost of meeting such standards by a combination of coal cleaning and FGD. For all 12 cases of hypothetical new plants, combined cleaning and FGD was calculated to be less expensive than FGD alone, using a basis of $/MM Btu of coal fired. These cost studies were actually completed prior to passage of the Resource Conservation and Recovery Act (RCRA) on October 21, 1976, and thus did not include ECT costs as part of the waste disposal costs of the coal-cleaning plants.

The purpose of this report is twofold: (1) to summarize our present understanding of comparative costs for selected coal-cleaning ECTs, and (2) to analyze the impact of coal-cleaning ECT costs on the economic trade-offs between coal cleaning at (or near) the mine and FGD at the customer utility plant.

BACKGROUND

LASL Study of Coal Waste Chemistry

The LASL study of coal waste chemistry began with the collection of samples of coal and refuse from three Illinois Basin cleaning plants processing high-sulfur coal. These plants have been designated Plant A, Plant B, and Plant C, respectively, in the annual reports of this project.[1,2,4] Other plants producing lower sulfur coal have subsequently been sampled for analysis, but chemical results sufficient for cost comparisons are available only for the first three.

Chemical and mineralogical analyses of feed coal, clean coal, and refuse (coal-cleaning waste) are essential to the conceptual design of ECTs and therefore to the calculation of the costs of alternative ECTs. Because the major pollution factor is the contamination of water run-off from refuse piles, information on the acidity and chemical content of water leachates is also needed for cost calculations. Some of the more critical information and data on Plants A, B, and C were extracted from the annual reports[1,2] and are summarized in Table I.

Assumptions about the basic method of disposal of the coal-cleaning waste must be made. For this report, it was assumed that the valley-fill method recommended as an alternative in *Underground Disposal of Coal Mine Wastes*[5] would be used. In this method, a narrow downward-sloping valley near the cleaning plant is filled, in benches, from the upper end. It is assumed that as the upper benches reach contour level, the pile is covered with sufficient soil to retard water percolation to one-third that of an uncovered pile. On that basis, Part I of the leaching results given in Table I corresponds to the effluent to be expected in the first five years of pile life (assuming 35 in./year of rainfall). The Part II results correspond to a pile 40-60 years of age. The drainage from such a waste pile has essentially the characteristics of acid mine drainage, with most of the dissolved solids being iron sulfates. Table I shows that Plant B produces a waste that is very reactive with water, even though the quantity of waste produced per ton of clean coal is considerably less than for the other two plants.

TABLE I

SUMMARY INFORMATION ON ILLINOIS BASIN PLANTS A, B, and C[1,4]

	Plant A	Plant B	Plant C
Sulfur in raw coal (%)	3.7	3.9	5.2
Ash in raw coal (%)	30.0	18.8	29.0
Cleaning-plant yield (%)	68	87	72
Sulfur in cleaned coal (%)	2.8	2.8	3.6
Ash in cleaned coal (%)	9.5	12.0	10.5
Waste produced (ton/ton clean coal)	0.47	0.15	0.37
FeS_2 in coal-cleaning waste (%)	18.4	26.0	29.4
Continuous leaching results,[a] Part I[b]			
pH	2.9	1.7	2.4
Total dissolved solids (ppm)	27 200	81 000	31 000
Continuous leaching results,[a] Part II[c]			
pH	3.3	1.7	2.6
Total dissolved solids (ppm)	16 000	69 000	16 000

[a]Column leaching of −3/8 inch refuse with distilled water, air atmosphere.

[b]Initial effluent water, equivalent in weight to less than 10% of refuse in the column.

[c]Effluent water sample taken after 20-40 wt% of water had passed through the column.

In an earlier report,[2] we presented a preliminary comparison of costs of different ECT scenarios for three hypothetical plants of the same cleaning yield and throughput. Such a basis is useful for certain comparisons, but calculations based upon varying throughputs and yields are also desirable to reflect actual practice and are presented here.

Environmental Control Technology Options

Ten ECT options have been evaluated for costs of implementation, with varying degrees of accuracy in the cost data. The cost figures presented reflect the technological difficulty and feasibility of the 10 options considered as ECTs for coal-cleaning wastes.

The principal environmental problem posed by coal-cleaning waste is that the pyrite and marcasite in the waste is oxidized to sulfuric acid in the presence of air, water, and *T. ferrooxidans*. The sulfuric acid is usually sufficiently concentrated to dissolve out numerous metallic constituents, with large quantities of iron being present in the leachate. Any ECT intended to *prevent* sulfuric acid formation must eliminate either the air, the water, or the oxidizable sulfur compounds in the waste, or inactivate *T. ferrooxidans* by maintaining alkaline conditions. *Post*treatment of pile drainage comprises ECTs designed to neutralize the acid in the effluent and remove the metal ions by some sort of precipitation, adsorption, flocculation, or ion-exchange phenomenon.

Option 1. Calcining to Semivitreous State. If coal-cleaning waste containing FeS_2 as either pyrite or marcasite is heated above 1200°C in a kiln, all of the sulfur is either driven off as SO_2 (principally) or encapsulated with insoluble iron oxides in a partially glassy solid as a clinker. This clinker is essentially inert and may be disposed of in any convenient manner. The heat of combustion of the FeS_2 plus that of pelletized coal fines produced by the cleaning plant may be sufficient to provide the energy for calcination itself. However, an FGD plant is required. Although the FGD plant for kiln gases is somewhat smaller than that required for a coal-fired utility plant because of the high concentration of SO_2 in the gas, it is quite expensive.

Option 2. Calcining to Nonacidic State. LASL research has established that about 60% of the FeS_2 in the waste can be oxidized to iron sulfates, and retained in an ash that does not release hazardous levels of trace elements. This can and must be done at lower temperature (about 600-700°C) in the presence of limestone. One problem is that the remaining sulfur still passes out as SO_2 and must be removed from the off-gases. It is hypothesized, however, that the comparatively simple expedient of absorbing this SO_2 in milk of lime [$Ca(OH)_2$ suspension] and *recycling* the resultant material to the kiln will suffice for disposal. Despite some known impediments to the process (which was once widely used in the sulfite process of wood-pulp manufacture), it has the potential of being far less expensive than Option 1. A conceptual design for cost purposes has therefore been undertaken. But, although less expensive than Option 1, Option 2 is still not competitive with a number of alternative technologies.

Option 3. Lime-Limestone Slurry Coating of Waste Prior to Disposal. In this option the slurry coating, applied immediately prior to dispatch to the disposal area, neutralizes any acid which has already formed during processing and supplies enough additional alkali to inactivate *T. ferrooxidans*. The process is being studied at LASL with very promising early results. The amounts of lime and limestone used in the cost calculations are projected to be the most that would be required to "permanently" inactivate the undesirable bacteria. Obviously, a longer test period will be required before the process can be declared technologically viable. Although generally a little more expensive than Option 8, it has a number of potential advantages that should make it *the* ECT. For this reason, Option 3 costs have been used in the later calculations for total costs of environmental protection.

Option 4. Direct Addition of Lime to the Pile. Direct addition of hydrated lime $Ca(OH)_2$ to the pile has the same effect as Option 3. LASL leaching studies have shown that as little as 5% lime added to finely divided waste prevents acid formation and dissolution of metal ions. However, there is some question about the uniformity of dispersion and about covering the surfaces of the waste with direct addition of solid powdered lime to the pile at the time the waste is spread and bulldozed. Field experiments are required to prove this technology. Until the minimum effective dosage is demonstrated in the field, a conservative figure of 25% of the lime theoretically required to neutralize sulfuric acid has been used in the cost calculations.

Option 5. Codisposal with Alkaline Soil. Mixing the waste with a sufficient amount of alkaline soil and compacting the resulting mass has three effects. (1) The alkali neutralizes any acid already formed and inactivates the bacteria. (2) The mass of soil fills the voids between the waste particles, reducing permeability and the rate of water percolation. (3) Air accessibility is also reduced. This technology is only useful when a large quantity of alkaline soil is immediately adjacent to the disposal area, and is somewhat wasteful of energy because large quantities of liquid fuel are used moving earth.

Options 6 and 7. Codisposal with Fly Ash. The fly ash from coal-burning plants presents a large-scale solid waste disposal problem. The fly ash is, of its nature, somewhat alkaline. Moreover, certain fly-ash recovery systems involve a modification in which the SO_2 recovery system is ahead of the baghouse, so that carried-over limestone fines from the FGD system are mixed with the fly ash from the burned coal. The result is material that is estimated to have one-twelfth the neutralizing power of lime (CaO). Unless the coal-burning plant is immediately adjacent to both the coal-cleaning plant and the disposal area, a great deal of petroleum energy must be expended to haul the ash to the disposal area. The chemical effect of the fly-ash options is essentially the same as that of codisposal with alkaline soil. Costs for Options 6 and 7 were based on the consistent assumption of a coal waste disposal area immediately adjacent to the cleaning plant. The distance from the coal-burning (power) plant was assumed to be 15 road miles.

Option 8. Lime Neutralization/Precipitation of Effluent. Assuming that an impermeable soil base exists or has been put in place before building the cleaning waste disposal pile, drainage from the pile may be collected and chemically or physically purified before release to a watercourse. In Option 8, the concept is that lime is added continuously to the effluent followed by passage through a conventional mechanical clarifier system. Based on laboratory

observations, recycling of 12 vol% of the sludge to the pile was incorporated in the calculations. This technology has the advantages of being the least expensive of all the options considered, for most cases, and of being a proven technology in current use in the coal industry. However, there are two very important drawbacks to any posttreatment (that is, effluent treatment). (1) It is difficult to ensure that all, or even most, of the effluent is being captured and treated. (2) Effluent treatment must continue for 100-plus years after the active life of the pile has been reached.

The costs used in this report allow for a trust fund to pay the expenses of continuing treatment, but such a situation is essentially awkward from both an operational and governmental standpoint.

Options 9 and 10. Other Effluent Treatments. Reverse osmosis is a physical process by which the majority of the effluent water is cleansed of polluting ions. However, a highly polluted reject-water stream is also produced. This reject stream is normally sent to evaporation ponds for further concentration and ultimate disposal of the pollutant solids. Ion exchange is a physicochemical process that similarly produces a pure-water stream and a lower volume stream of concentrated waste that must be evaporated. Both processes are more expensive than Option 8, have the same general drawbacks, and present the additional problem of ultimate disposal of their concentrated waste streams.

Hoffman-Muntner Engineering-Economic Analysis

The Hoffman-Muntner Corporation has prepared a very careful engineering-economic study in which 12 hypothetical mine cleaning plants (each cleaning a well-characterized low- to medium-sulfur coal) are paired with 12 utility customers in various locations in the Eastern United States.[8] Assumptions and methods of calculation are specifically stated and example calculations are presented. The authors obtained the most detailed possible cost estimation information, as of December 1975, to calculate coal-cleaning and FGD costs. Various benefits of cleaning coal, including higher selling price per ton for the mine owner (because of higher Btu content), reduced transportation cost (per million Btu), reduced ash disposal costs at the power plant, and the reduced FGD costs were evaluated as precisely as available data would allow. Because certain costs vary from locality to locality in the Eastern United States, specific coal-producing locations and utility plant locations were chosen to be paired up for evaluation, based on historical patterns of supplier-customer relationships. Actual channel samples of coal from the location of the hypothetical supplier were used as the basis for the coal characteristics and cleanability. Actual emission standards at the customer location were used to calculate the amount of FGD required.

The authors draw no generalizations from the data, except to point out that coal cleaning and FGD together have the advantage over FGD alone in all the cases of new plants considered. Because each supplier-utility pair represents different circumstances, the authors recommend that future comparisons be done on a case-by-case basis. A consistent 90% cleaning plant yield was used as a basis for calculations, because, as Deurbrouck and coworkers[6,7] have shown, very little additional sulfur is removed by reducing the yield below 90%. This phenomenon was specifically observed for northern Appalachian coals, but data for other eastern coal regions show that it is a good approximation for a fairly broad spectrum of coals.[7]

The Hoffman-Muntner report uses the coal cleanability data published by Cavallaro, Johnston, and Deurbrouck.[7] This source provides the only broad-based consistent set of coal cleanability data available to researchers and engineering analysts. It provides extensive analysis and comparisons of 455 different coal channel samples, representing over 70% of the seams producing utility coal in the US. Run-of-mine (ROM) coal from a given seam, however, will always run higher in ash content and will often be higher in sulfur content than a channel sample from the same seam. Thus, cleanability of ROM coal from a given location and coalbed can sometimes differ significantly from the data reported by Cavallaro et al.

Although the authors of the Hoffman-Muntner report do not offer any generalizations, and even though these data are results of a systematic process, at least two very strong statistical associations show up in their results. The chances are only 1 in 1000 that they might have occurred fortuitously.

First, the sulfur content of the cleaned coal correlates highly with the sulfur content of the raw coal ($r = 0.9$). Presumably this association reflects the consistent use of a 90% cleaning yield in the computation of the data. Second, the combined environmental cost (cleaning plus FGD) is highly correlated ($r = 0.92$) with the sulfur difference between the clean coal and the emission standard. In other words, the more sulfur that must be removed, the more it will cost. This result is what one would expect intuitively.

Both of the above associations are for channel samples that, for the most part, were fairly low in ash. The large amount of ash in some of the ROM samples could be expected to provide an interaction effect that might modify these associations. Unfortunately, with only three ROM samples available for this report, no further statistical comparison can be drawn.

METHODOLOGY—COST CALCULATIONS

ECT costs have been calculated for six coal-cleaning plants for this report. Three of the plants are hypothetical plants producing 2 070 000 tons of clean coal per year and 621 000 tons of waste.[3,5] In comparing costs, the chemical composition and characteristics of the waste from each of these first three plants, designated A(H), B(H), and C(H), were assumed to be the same as Illinois Basin Plants A, B, and C as listed in Table I. The purpose of the comparisons among these three hypothetical plants was to determine the effects of waste composition on ECT costs for plants of the same throughput and yield. The other three plants for which cost calculations were made were for the actual operating yields of the respective plants and for throughputs of 1 325 758, 1 400 000, and 1 325 758 tons/year of clean coal. These latter plants are designated Plants A), B(A), and C(A), respectively. (The throughputs were assumed for computational convenience in later cost comparisons and approximate those of the actual plants.) The purpose of comparisons among the latter plants was to determine the influence of throughput and yield, along with waste composition, on ECT costs.

Comparative Costs, Water Pollution Abatement/Prevention Options

Ten alternatives for correcting or preventing water pollution from acid drainage produced by piles of coal-cleaning wastes are compared. Options 1-3 comprise pretreatments of the waste before it is disposed to the pile. Options 4-7 refer to treatments undertaken as the pile is being formed. Options 8-10 refer to chemical treatment of the pile effluent. All costs are based on March 1978 dollars.

Option 1. Calcining to Vitreous State (Conventional FGD). Cost for this option was estimated only roughly. The method follows. For Plant A(A), the *FGD cost* for burning the raw coal (see Appendix) was incremented by an arbitrary sum for capital and operating costs of the kilns. It was assumed that the size differential cancelled the time base differential. Costs for the other five plants were determined by ratioing to Plant A(A) and changing the two factors of cleaning yield and fraction of FeS_2 in the waste.

Option 2. Calcining to Nonacidic State (Lime-Limestone Recycle). Capital costs for kilns, absorption towers, and baghouses were estimated at \$7 000 000, \$8 500 000, and \$9 000 000 for plants A(H), B(H), and C(H), respectively, with the remainder of the cost being that of the lime and limestone required for neutralization of the SO_2 and maintaining an alkaline environment in the kilns. No operating costs are included. Costs for Plants A(A), B(A), and C(A) were determined by ratioing.

Option 3. Lime-Limestone Slurry Coating. Capital cost for this option was calculated to be \$376 000 and essentially independent of plant throughput in the range here considered. The operating expense, other than materials, is also independent of throughput. Lime and limestone cost is a function of the tonnage and *not* the composition of waste. The data in the tables are based on an annual charge of \$127 651 plus cost of lime and limestone, using 0.6 lb of lime and 3.0 lb of limestone per 100 lb of total waste to calculate the materials cost. Costs were determined independently for each of the six plants.

Option 4. Direct Addition of Lime to the Pile. For each plant, the cost of lime stoichiometrically equivalent to one-quarter of the FeS_2 in the waste was calculated. Lime cost was taken at $45.00/ton, the same figure used in all options. No capital charges or additional operating expenses have been included.

Option 5. Codisposal with Alkaline Soil. Costs for this option are based on a soil with an alkalinity equivalent to 10% content of $CaCO_3$ and a requirement of neutralizing power equivalent to 11% of the FeS_2 in the waste. For Plant A(H) this amounts to 650 000 cubic yards of soil/year. Capital and operating costs for the scraper, hauler, and additional bulldozer necessary for this option were calculated. Soil hauling distance was assumed to be 400 yards. No additional compaction, other than bulldozing, was included. Other plants were ratioed to Plant A(H) using the factors of volume of waste and fraction FeS_2 in waste.

Options 6 and 7. Codisposal with Fly Ash. Cost calculations for these two options were made on a similar basis to Option 5. The amount of fly ash to be codisposed with coal-cleaning waste was calculated to be equivalent to the addition of 25% of hydrated lime to the pile.[2] In addition to the extra capital and operating costs of earth-moving equipment at the disposal site, the cost of uploading, truck hauling for 15 miles, and unloading are included. A credit from the power plant is also included.

Option 8. Lime Precipitation/Clarification of Effluent. For purposes of cost calculation, a 20-year active life of the waste pile was assumed. The costs for the first 5 years (8a) and the last 5 years (8b) differ because the acreage of the pile increases, causing more volume of contaminated effluent to flow out of the pile as a result of rainfall. Basic assumptions employed in the calculation included (1) rainfall, 35 inches/year; (2) pile growth rate, 12.5 acres/year; (3) pile areas over one year old are covered with topsoil; (4) standard commercial mixer and mechanical clarifier producing 88% clear water overflow and 12% slurry returned to pile; and (5) 1500 feet of slurry return pipeline. Equipment size and lime usage, and their related capital and operating costs were calculated separately for Plants A(H), B(H), and C(H), using laboratory leaching data to determine the quantities involved for effluent treatment in relation to mass and composition of the solid refuse.[1,2] Costs for Plants A(A). A(B), and A(C) were calculated by ratioing the masses of solid refuse to their respective hypothetical plants. This procedure is presumably slightly in error on the high side for Plant B(A), but should give quite reasonable comparative figures for all three actual plants. Costs were calculated from standard 1972 engineering cost data and updated to March 1978 using the *Chemical Engineering Plant Cost Index*. Further details may be found in the Appendix and Ref. 2.

Options 9 and 10. Reverse Osmosis and Ion Exchange of Effluent. Ackenheil and Associates Geo Systems, Inc., published a report[8] in 1972 on mitigation of acid mine drainage in two West Virginia creeks. In this report costs were developed for reverse osmosis and ion exchange treatments of the polluted water. Since the pH and total dissolved solids in these streams approximated the early stages of effluent from Plant C, it was decided to estimate costs for Plants C(H) and C(A) by using the published cost data and updating to March 1978 using the *Chemical Engineering Plant Cost Index*. The effluents from the other two plants are sufficiently different that no accurate cost projections could be made for these, given the Ackenheil cost data alone.

Comparison of Coal-Cleaning and FGD Costs

Cases 8a and 8b of the Hoffman-Muntner report[3] refer to an Illinois Basin supplier providing coal to a utility in Central Tennessee, 400 miles from the mine. In developing the costs for Plants A(A), B(A), and C(A), the same coal pricing pattern and same distance to customer were used as were considered in Cases 8a and 8b of the Hoffman-Muntner report. Complete case calculations for the three plants and their customers were made and are presented in the Appendix of this report. The Hoffman-Muntner procedures were followed with minor additions. Because the various costs in their report were based on accurate December 1975 figures, it was decided to use the same costs because direct comparisons with the entire set of Hoffman-Muntner cases could be made and price structures have not escalated uniformly in the peiod since the above costs were obtained. Thus, a great deal of time could be saved if

updated figures were not required. The coal cleanability data required in the calculations were obtained from LASL data on the actual cleaning performance of the plants. ECT costs for Option 3 were included in the costs of coal cleaning.

COST RESULTS AND COMPARISONS

Water Pollution Abatement/Prevention Options

Cost comparisons in March 1978 dollars of 10 pollution abatement options for the three hypothetical coal-cleaning plants are presented in Table II. In this table, we compare three coal-cleaning plants with the same throughput and depth of cleaning of rather high-sulfur ROM coals. The waste compositions differ in quantity of FeS_2 and in reactivity to water. Option 8 is clearly the least expensive route for Plants A(H) and C(H), but is much more costly than Option 3 for Plant B(H).

Table III presents cost comparisons similar to those in Table II for the three actual plants in the Illinois Basin that were sampled in this LASL study. The allowance for differences in the clean coal yield from the three different actual operations changes the relative cost comparisons by a very significant amount. Option 8, however, is still the least expensive for Plants A and C, and Option 3 remains the least expensive for Plant B. This difference is due to the exceptionally high acidity of the leachate from the waste from Plant B. Although plant B produces the least proportion of waste of the three, the water quality of its pile effluent is by far the poorest.

Combined Emission Control Technology Costs for Coal Producer and Consumer

The total costs of coal cleaning, including ECT costs, the benefits of cleaning, and the costs of FGD were calculated for a hypothetical customer of actual plants A, B, and C. The complete calculations are in the Appendix of this report. The three cases A(A), B(A), and C(A) from this study are compared in Table IV with two literature cases.[8] Hoffman-Muntner Case 8 relates to an Illinois Basin mine and cleaning plant, with a comparatively low-sulfur raw

TABLE II

COMPARATIVE COSTS FOR VARIOUS ECT OPTIONS WITH COAL-CLEANING WASTE

Option	Cost ($/ton of Product Coal)		
	Plant A(H)	Plant B(H)	Plant C(H)
1. Calcining, conventional FGD	5.79	5.94	8.04
2. Calcining, lime-limestone recycle system	2.14	2.80	3.08
3. Lime-limestone slurry coating	0.30	0.30	0.30
4. Direct addition of lime to pile[a]	0.64	0.90	1.02
5. Codisposal with alkaline soil	0.81	1.15	1.30
6. Codisposal with fly ash	3.72	5.26	5.95
7. Codisposal with limestone-modified fly ash	2.48	3.51	3.97
8a. Lime precipitation/clarification of effluent (first five years)	0.083	0.83	0.051
8b. Lime precipitation/clarification of effluent (last five years)	0.098	1.11	0.059
9. Reverse osmosis, effluent			0.20
10. ion exchange, effluent			0.29

[a]Labor cost not included

TABLE III

COSTS FOR VARIOUS ECT OPTIONS WITH COAL-CLEANING WASTE

Option	Cost ($/ton of Product Coal)		
	Plant A(A)	Plant B(A)	Plant C(A)
1. Calcining, conventional FGD	8.30	3.40	9.89
2. Calcining, lime-limestone recycle system	3.36	1.39	3.99
3. Lime-limestone slurry coating	0.50	0.22	0.44
4. Direct addition of lime to pile[a]	1.01	0.45	1.33
5. Codisposal with alkaline soil	1.27	0.57	1.69
6. Codisposal with fly ash	5.84	2.62	7.71
7. Codisposal with limestone-modified fly ash	3.90	1.75	5.15
8a. Lime precipitation/clarification of effluent (first five years)	0.13	0.42	0.066
8b. Lime precipitation/clarification of effluent (last five years)	0.15	0.55	0.076
9. Reverse osmosis, effluent			0.26
10. Ion exchange, effluent			0.38

[a]Labor cost not included.

TABLE IV

COSTS OF MEETING ENVIRONMENTAL STANDARDS WITH COAL CLEANING AND FGD[a]

Parameter	Range	Cases				
		A(A)I,II	B(A)I,II	C(A)I,II	8A,B[b]	12A,B[b]
Sulfur in raw coal (%)		3.7	3.9	5.2	1.54	3.8
Sulfur in clean coal (%)		2.8	2.8	3.6	0.9	2.16
Ash in raw coal (%)		30.0	18.8	29.0	2.0	11.0
Cleaning plant yield (%)		68	87	72	90	90
Combined coal-cleaning and FGD cost ($/ton)	High	8.62	7.67	9.01	3.32	6.31
	Low	5.88	6.76	6.65	2.71	5.66
Combined coal-cleaning and FGD cost ($/MMBtu)	High	0.327	0.306	0.341	0.132[c]	0.225[c]
	Low	0.223	0.270	0.252	0.108[c]	0.201[c]
Combined cost advantage over FGD alone ($/MMBtu)	High	0.055	0.038	0.088	0.052[d]	0.069[d]
	Mid	0.003	0.020	0.044	0.040[d]	0.057[d]
	Low	−0.049	0.002	-0.001	0.028[d]	0.045[d]

[a]Emission Standard is 1.2 lb SO_2 per million Btu in all cases.

[b]From pp. 158-162, 203-207 of Ref. 3.

[c,d]These figures do not include ECT costs for water pollution abatement/prevention at the coal-cleaning plants. Costs (c) should be increased, and advantages (d) decreased by approximately $0.007 to be comparable to Cases A(A), B(A), and C(A), using Option 3.

coal, supplying the same hypothetical customer as in the cases from this study. Case 12 is for a mine in another coal region producing a high-sulfur coal. Mining and transportation costs are higher there than for the three cases in this study. Case 12 was selected for comparison because it was the only one with a raw coal containing about as high a sulfur content as Plants A and B in our study. Costs are in December 1975 dollars.

For perspective on the effect of the ECT option chosen, the combined costs of meeting water quality standards at the coal-cleaning plant and air quality standards at the electric utility plant were calculated for the various options and plants. The figures are in December 1975 dollars. The results are presented in Table V, for the actual plants A, B, and C. Table V may be compared directly to Table III by reducing all values in Table III by a factor of 0.8.

DISCUSSION

Comparative Costs: Water Pollution Abatement/Prevention Options

The alternative ECTs are compared in Table I on a consistent depth-of-cleaning basis. The method of comparing three hypothetical plants with the same throughput and fractional recovery of cleaned coal suppresses the effects of raw coal composition and depth of cleaning to emphasize the effects of waste composition. The ECT costs for Options 1, 2, and 4-7 are affected strongly and directly by the sulfur level in the waste. This effect is clearly seen in moving from left to right in Table II, reflecting the successive increases in sulfur content of the waste in moving from Plant A to Plant B and then to Plant C (see Table I). Because Option 3 cost depends only on the relative volume of waste, it is constant in Table II.

Option 8 presents a different situation. LASL leaching studies have shown that the sulfur-bearing minerals in Plant B waste are highly reactive and produce a stronger (more acidic) leachate than the wastes from Plants A and C. On the other hand, the solid waste from Plant C, although of high-sulfur content, produces a rather weakly acidic leachate. (Both comments refer to laboratory results corresponding to about the first 60 years of pile life in commercial operations.) These marked differences in leaching behavior account for the twentyfold variation in effluent treatment costs listed in Options 8a and 8b of Table II.

TABLE V

COMBINED COSTS OF MEETING WATER QUALITY STANDARDS AT COAL-CLEANING PLANT AND STACK EMISSION STANDARDS AT ELECTRIC POWER PLANT

Option	Cost of Cleaning Option and FGD ($/ton)		
	Plant A(A)	Plant B(A)	Plant C(A)
1. Calcining conventional FGD	13.49	9.76	15.39
2. Calcining lime-limestone recycle system	9.54	8.15	10.67
3. Lime-limestone slurry coating	7.25	7.22	7.83
4. Direct addition of lime to pile	7.66	7.40	8.54
5. Codisposal with alkaline soil	7.87	7.50	8.83
6. Codisposal with fly ash	11.52	9.14	13.65
7. Codisposal with limestone-modified fly ash	9.97	8.44	11.60
8a. Lime precipitation/clarification of effluent (first five years)	6.95	7.38	7.53
8b. Lime precipitation/clarification of effluent (last five years)	6.97	7.48	7.54
9. Reverse osmosis effluent			7.69
10. Ion exchange effluent			7.78

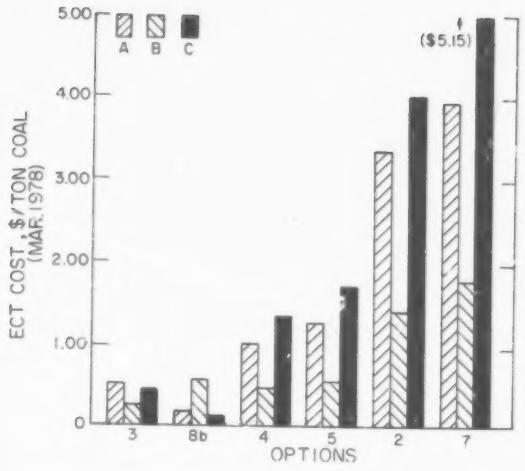

Fig. 1.
Comparative costs of ECT, actual coal-cleaning plants.

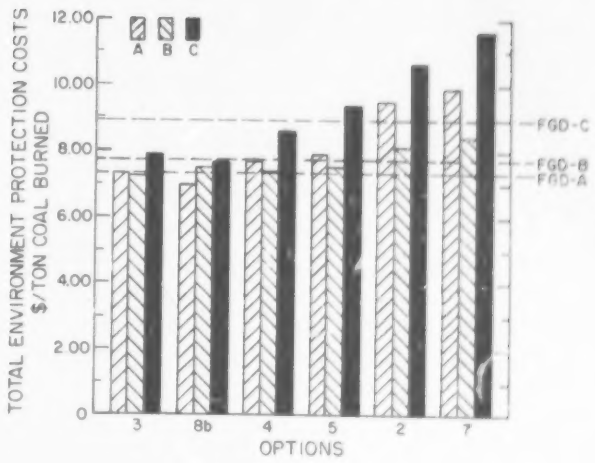

Fig. 2.
Electric utility environmental protection costs for various cleaning waste ECT options (1975 dollars).

When the cleaning yields of the actual plant operations are taken into account, a different and more realistic picture develops. The high cleaning yield of Plant B (87%) compared with the lower (about 70%) yield of the other two results in much less waste per ton of product coal to which an ECT process must be applied. This results in less control cost for Plant B in dollars per ton of cleaned coal produced (see Fig. 1). The only exception is Option 8, where the high acidity of the leachate places Plant B at a cost disadvantage in spite of its lower volume of solid waste.

Coal Waste ECT Costs Incorporated in Overall Environmental Protection Costs

If the costs of adding an environmental protection process to a coal-cleaning plant are added to the overall costs of meeting standards for coal-fired electric power plants, the additional economic burden on the consumer is very slight, assuming one of the two lower cost processes is used. Estimations based on a coal-cleaning ECT costing $0.007/mm Btu indicate an added cost of less than 0.2 mills/kWh, at 1975 prices. Even assuming a doubling of cost by late 1979, a current cost increase of considerably less than 0.4 mills per kWh is a fair estimate of what the consumer would pay for adding an ECT process to a coal-cleaning operation. Since the overall environmental protection cost (based on Hoffman-Muntner figures) appears to have been about 3 mills/kWh in 1975 dollars, the ability of coal-fired plants to compete favorably with oil-fired plants would seem to be unaffected by use of inexpensive ECTs for mitigating the effects of coal-cleaning waste on the environment, given a continuing high price of fuel oil.

FGD is a very expensive environmental control technology. To illustrate the advantages of using coal cleaning and *its* ECT, Fig. 2 presents costs of meeting environmental standards in two ways. The bar graphs for selected ECT options show the combined cost, in $/ton of coal burned, of meeting environmental standards by coal cleaning near the mine and FGD at the power station. The horizontal lines show the cost of FGD at the power station assuming no cleaning of the feed coal to Plants A, B, and C. (In determining these latter costs, adjustment was made for the lower Btu value of the raw

coals.) Combination costs using several of the less expensive ECTs for coal cleaning show a significant cost advantage over applying FGD alone to raw coal. However, the more expensive ECTs applied to coal-cleaning waste tilt the economics in favor of *not* cleaning the coal.*

The range of coal-cleaning costs for each of the three actual plants discussed in this report is greater than those reported by Hoffman-Muntner Corp. for any of their 12 cases of new plants.[3] Likewise, the monetary advantages of combining cleaning with FGD, as compared with FGD alone, show a wider range for the cases in this report than in the previous work. The lower cleaning plant yields for the plants in this study (68-87%) as contrasted to the constant 90% yields assumed in the Hoffman-Muntner calculations appear to be one factor, and the higher ash contents of the raw coals another. Lower cleaning plant yield means more expense for mining raw coal for each ton of clean coal shipped. High initial ash content of the raw coal means greater comparative benefits in selling price and other factors as a result of cleaning. Since the method of calculation involves a range in values both of mining costs and selling prices, the two factors combine to produce a larger range of effective cleaning costs when high-ash coal is deep-cleaned, as compared with shallower cleaning of low-ash material.

Examination of the complete case calculations in the Appendix shows that it would be quite impractical for a utility plant to use the raw coal input to Plant C because of the likelihood that emission standards would be out-of-compliance more frequently than regulations permit. Likewise, the high ash in the raw-coal feed to Plant A makes it very undesirable for utility boiler applications. These high-sulfur high-ash coals *must* be cleaned, otherwise there would be essentially no market for them.

These cost comparisons of FGD with coal cleaning vs FGD alone point out certain purely economic reasons, which have been quantified, for cleaning or not cleaning coals. But the cost data do not reflect the economics of certain practical aspects of steam power generation that are difficult to quantify. For example, it is known that accelerated deterioration of a steam boiler and its auxiliaries occurs with very high ash content coals. The costs have not been precisely quantified, but operators skirt the problem by not using such coals except in cases of severe shortage of more desirable fuel.

In summary, it appears that the additional cost of the less expensive coal-cleaning-waste ECTs does not significantly alter the cost differential between FGD with coal cleaning and FGD alone. Furthermore, these less-expensive ECTs should not impair the ability of coal-fired utility power stations to compete with oil-fired stations.

*Since no estimate of RCRA compliance costs were available at the date of writing, these costs have not been added to either the cleaning plant or the power station environmental protection expenses.

CONCLUSIONS

ECT costs for coal-cleaning wastes are a strong function of the depth of cleaning required for the raw coal.

These costs for coal cleaning depend on the ECT selected. For one actual plant doing deep cleaning, these ranged from $0.076 to $9.89 per ton of product coal, based on March 1978 costs.

Using the less expensive ECTs, the ECT costs for coal cleaning may add about 6-8% to the differential production costs of cleaning coal.

For the purpose of supplying electric utility customers, coal cleaning reduces the cost of FGD. This produces an overall lower cost of meeting environmental standards, even with modest ECT costs for the coal-cleaning waste included.

Applying the less expensive ECT options to coal-cleaning wastes adds approximately 0.2 to 0.4 mills/kWh to the cost of producing electric power (1979 costs). This compares with an estimated current (1979) cost of 5 mills/kWh required to meet stack gas emission standards. The ability of coal-fired utility plants to compete favorably with oil-fired plants would seemingly be unaffected by emplacing the less expensive ECTs for coal-cleaning wastes.

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APPENDIX

DETAILED CASE ANALYSES FOR COMBINED COAL-CLEANING AND FGD PROCESSES: ILLINOIS BASIN PLANTS A(A), B(A), AND C(A) IN CONJUNCTION WITH A HYPOTHETICAL ELECTRIC UTILITY CUSTOMER IN THE SAME GEOGRAPHICAL AREA

Method of calculations taken from Ref. 3. All costs are as of December 1975 to be consistent with Ref. 3.

CASE A(A)-I

1.0 Case conditions: Combined use of physical cleaning followed by stack gas scrubbing

1.1 Coal use area: Central Kentucky-Tennessee

1.2 Emission standards

New: 1.2 lb of SO_2 per MM Btu

1.3 Coal region of origin: Illinois Basin

Coalbeds: Illinois No. 5 and No. 6, or equivalent

1.4 Raw coal*

Btu/lb: 10 210	Ash: 30%
lbs. SO_2/MM Btu: 7.25	Sulfur: 3.7%
	MM Btu/ton: 20.42

*As-received values.

1.5 Clean coal

Sulfur: 2.8%
Ash: 9.5%
Btu/lb: 13 200
Btu increase: 29.3%
Btu recovery: 87.9%
MM Btu/ton: 26.40
lbs. SO_2/MM Btu: 4.24
Cleaning-plant yield: 68%

1.6 Transportation

Assumed cost per ton: $4.00

1.7 Assumed plant size: 500 MW

1.8 Useful life of boiler: 25 years

1.9 Assumed ash disposal cost: $4.00/ton

1.10 Cleaning plant

Cost: $18 000 per ton-hour input capacity*
Utilization: 38.58%**

1.11 Assumed annual scrubber charges (capital charges) as percent of original investment: 15.55%

2.0 Coal-cleaning cost factors

2.1 Cleaning-plant costs

Amortization: $0.80/ton
Basic O&M: $1.10/ton
ECT: $0.40/ton

2.2 Additional cost of raw coal to preparation plant to provide for one ton of cleaned coal, when raw coal cost is

$7.00, additional cost is $3.29
$9.00, additional cost is $4.24
$11.00, additional cost is $5.17

2.3 Cleaning-plant tax and insurance burden: $0.12/ton

2.4 Total differential production cost to preparation plant operator to provide a ton of cleaned coal, when raw coal cost is

$7.00, differential cost is $5.71†
$9.00, differential cost is $6.66†
$11,00, differential cost is $7.59†

3.0 Assessable benefit factors associated with clean coal

3.1 Added coal value per ton due to higher heat content of coal, when F.O.B. mine coal price is

$12.00, benefit is $2.72
$14.00, benefit is $3.18
$16.00, benefit is $3.63

3.2 Transportation cost saving due to increased heat content of the coal: $0.69/ton

3.3 Saving in ash disposal cost: $1.52/ton

3.4 Saving in grinding cost: $0.09/ton

3.5 Saving in benefit payment: $0.13/ton

3.6 Saving in maintenance: $0.33/ton

3.7 Total benefits per ton of coal cleaning when F.O.B. mine coal selling price is

$12.00, benefit is $5.48
$14.00, benefit is $5.94
$16.00, benefit is $6.34

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*Amortized over 15 years, 8% interest on unpaid balance.

**Based upon 260 days/year at 13 hour/day—3380 hours/year.

†See pp. 45-46 of Ref. 3.

4.0 Differential cleaning cost less benefits ($/ton)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	0.23	−0.23	−0.63
9.00	1.18	0.72	0.32
11.00	2.11	1.65	1.25

5.0 Stack gas cost factors
5.1 Boiler capacity: 500 MW
5.2 Utilization factor: 7000 hours/year
5.3 Tons of coal burned per year: 1 325 758
5.4 Minimum scrubber requirements,
Scrubber rating: 399 MW
Flue gas cleaned: 79.8%
5.5 Design scrubber requirements,
Scrubber rating: 458 MW
Flue gas cleaned: 91.6%
5.6 Scrubber capital cost: $26 586 000
5.7 Scrubber capital charges per year: $4 134 123
5.8 Capital contribution per ton of coal: $3.12
5.9 Fuel and electricity cost per ton of coal: $0.70
5.10 O&M costs per ton of coal
Limestone: $0.51
Maintenance: $0.92
Fixation chemicals: $0.42
Oper. labor: $0.12
Overhead: $0.72
5.11 Total stack gas cost per ton of coal burned: $6.51
5.12 Total stack gas cost per million Btu's consumed: $0.247
6.0 Cost per ton of coal burned to meet emission standards ($/ton)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	6.74	6.28	5.88
9.00	7.69	7.23	6.83
11.00	8.62	8.16	7.76

7.0 Cost per million Btu to meet emission standards ($/MMBtu)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	0.255	0.238	0.223
9.00	0.291	0.274	0.259
11.00	0.327	0.309	0.294

CASE: A(A)-II

1.0 Case conditions: Sulfur cleanup exclusively by stack gas scrubbing

1.1-1.11 (Same as for Case A(A)-I)

2.0-4.0 (Not applicable)

5.0 Stack gas cost factors

5.1 Boiler capacity: 500 MW

5.2 Utilization factor: 7000 hours/year

5.3 Tons of coal burned per year: 1 714 032

5.4 Minimum scrubber requirements

Scrubber rating: 463 MW

Flue gas cleaned: 92.7%

5.5 Design scrubber requirements*

Scrubber rating: 500 MW

Flue gas cleaned: 100%

5.6 Scrubber capital cost: $30 295 000

5.7 Scrubber capital charges per year: $4 711 000

5.8 Capital contribution per ton of coal: $2.75

5.9 Fuel and electricity costs per ton of coal: $0.59

5.10 O&M costs per ton of coal

Limestone: $0.52

Maintenance: $0.66

Fixation chemicals: $0.47

Oper. labor: $0.08

Overhead: $0.56

5.11 Total cost per ton of coal burned to meet emission standards: $5.68

5.12 Total cost per million Btu consumed to meet emission standards: $0.278

CASE B(A)-I

1.0 Case conditions: Combined use of physical cleaning followed by stack gas scrubbing

1.1 Coal use area: Central Kentucky-Tennessee

1.2 Emission standards

New: 1.2 lb of SO_2 per MM Btu

1.3 Coal region of origin: Illinois Basin

Coalbeds: Illinois No. 5 and No. 6, or equivalent

*This scrubber will need to operate at close to design capacity.

1.4 Raw coal*
Btu/lb: 11 534
lbs SO_2/MM Btu: 6.76
Ash: 18.8%
Sulfur: 3.9%
MM Btu/ton: 23.07

1.5 Clean coal
Sulfur: 2.8%
Btu/lb: 12 500
Btu recovery: 94.3%
lbs SO_2/MM Btu: 4.48
Ash: 12.0%
Btu increase: 8.4%
MM Btu/ton: 25.00
Cleaning-plant yield: 87%

1.6 Transportation
Assumed cost per ton: $4.00/ton

1.7 Assumed plant size: 500 MW

1.8 Useful life of boiler: 25 years

1.9 Assumed ash disposal cost: $4.00/ton

1.10 Cleaning plant
Cost: $18 000 per ton-hour input capacity**
Utilization: 38.58%†

1.11 Assumed annual scrubber charges (capital charges) as percent of original investment: 15.55%

2.0 Coal-cleaning cost factors

2.1 Cleaning-plant costs
Amortization: $0.62/ton
Basic O&M: $0.78/ton
ECT: $0.18/ton

2.2 Additional cost of raw coal to preparation plant to provide for one ton of cleaned coal, when raw coal cost is
$7.00, additional cost is $1.05
$9.00, additional cost is $1.35
$11.00, additional cost is $1.64

2.3 Cleaning-plant tax and insurance burden: $0.12/ton

2.4 Total differential production cost to preparation plant operator to provide a ton of cleaned coal, when raw coal cost is
$7.00, differential cost is $2.75‡
$9.00, differential cost is $3.05‡
$11.00, differential cost is $3.34‡

3.0 Assessable benefit factors associated with clean coal

3.1 Added coal value per ton due to higher heat content of coal, when F.O.B. mine coal price is
$12.00, benefit is $0.93
$14.00, benefit is $1.09
$16.00, benefit is $1.24

3.2 Transportation cost saving due to increased heat content of the coal: $0.31/ton

3.3 Saving in ash disposal cost: $0.36/ton

3.4 Saving in grinding cost: $0.04/ton

3.5 Saving in benefit payment: $0.06/ton

3.6 Saving in maintenance: $0.24/ton

*As-received values.

**Amortized over 15 years, 8% interest on unpaid balance.

†Based upon 260 days/year at 13 hours/day—3380 hours/year.

‡See pp. 45-46 of Ref. 3.

3.7 Total benefits per ton of coal cleaning when F.O.B. mine coal selling price is
$12.00, benefit is $1.93
$14.00, benefit is $2.10
$16.00, benefit is $2.25

4.0 Differential cleaning cost less benefits ($/ton)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	0.82	0.65	0.50
9.00	1.12	0.95	0.80
11.00	1.41	1.24	1.09

5.0 Stack gas cost factors
5.1 Boiler capacity: 500 MW
5.2 Utilization factor: 7000 hours/year
5.3 Tons of coal burned per year: 1 400 000*
5.4 Minimum scrubber requirements
Scrubber rating: 407 MW
Flue gas cleaned: 81.3%
5.5 Design scrubber requirements
Scrubber rating: 467 MW
Flue gas cleaned: 93.5%
5.6 Scrubber capital cost: $26 940 000
5.7 Scrubber capital charges/year: $4 189 170
5.8 Capital contribution per ton of coal: $2.99
5.9 Fuel and electricity cost per ton of coal: $0.68
5.10 O&M costs per ton of coal
Limestone: $0.49
Maintenance: $0.89
Fixation chemicals: $0.40
Oper. labor: $0.12
Overhead: $0.69
5.11 Total stack gas cost per ton of coal burned: $6.26
5.12 Total stack gas cost per million Btu's consumed: $0.25
6.0 Cost per ton of coal burned to meet emission standards ($/ton)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	7.08	6.91	6.76
9.00	7.38	7.21	7.06
11.00	7.67	7.50	7.35

*This figure somewhat exceeds the actual capacity of the "real" cleaning plant B.

7.0 Cost per million Btu to meet emission standards ($/MMBtu)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	0.283	0.276	0.270
9.00	0.295	0.288	0.282
11.00	0.306	0.300	0.294

CASE B(A)-II

1.0 Case conditions: Sulfur cleanup exclusively by stack gas scrubbing

1.1-1.11 (Same as for Case B(A)-I)

2.0-4.0 (Not applicable)

5.0 Stack gas cost factors

5.1 Boiler capacity: 500 MW

5.2 Utilization factor: 7000 hours/year

5.3 Tons of coal burned per year: 1 517 122

5.4 Minimum scrubber requirements

Scrubber rating: 457 MW

Flue gas cleaned: 91.4%

5.5 Design scrubber requirements*

Scrubber rating: 500 MW

Flue gas cleaned: 100%

5.6 Scrubber capital cost: $30 713 000

5.7 Scrubber capital charges per year: $4 776 000

5.8 Capital contribution per ton of coal: $3.15

5.9 Fuel and electricity costs per ton of coal: $0.67

5.10 O&M costs per ton of coal

Limestone: $0.68

Maintenance: $1.07

Fixation chemicals: $0.55

Oper. labor: $0.11

Overhead: $0.88

5.11 Total cost per ton of coal burned to meet emission standards: $7.11

5.12 Total cost per million Btu consumed to meet emission standards: $0.308

CASE C(A)-I

1.0 Case conditions: combined use of physical cleaning followed by stack gas scrubbing

1.1 Coal use area: Central Kentucky-Tennessee

1.2 Emission standards

New: 1.2 lb of SO_2 per MM Btu

1.3 Coal region of origin: Illinois Basin

Coalbeds: Illinois No. 5 and No. 6, or equivalent

*The operating factor of safety is smaller than desirable for this design.

1.4 Raw coal*
Btu/lb: 10 472
lbs SO_2/MM Btu: 9.93
Ash: 29%
Sulfur: 5.2%
MM Btu/ton: 20.94

1.5 Clean coal
Sulfur: 3.6%
Btu/lb: 13 200
Btu recovery: 90.8%
lbs SO_2/MM Btu: 5.45
Ash: 10.5%
Btu increase: 26%
MM Btu/ton: 26.40
Cleaning-plant yield: 72%

1.6 Transportation
Assumed cost per ton: $4.00/ton

1.7 Assumed plant size: 500 MW

1.8 Useful life of boiler: 25 years

1.9 Assumed ash disposal cost: $4.00/ton

1.10 Cleaning plant
Cost: $18 000 per ton-hour input capacity**
Utilization: 38.58%†

1.11 Assumed annual scrubber charges (capital charges) as percent of original investment: 15.55

2.0 Coal-cleaning cost factors

2.1 Cleaning plant costs
Amortization: $0.75/ton
Basic O&M: $1.10/ton
ECT: $0.35/ton

2.2 Additional cost of raw coal to preparation plant to provide for one ton of cleaned coal, when raw coal cost is
$7.00, additional cost is $2.72
$9.00, additional cost is $3.50
$11.00, additional cost is $4.28

2.3 Cleaning-plant tax and insurance burden: $0.12/ton

2.4 Total differential production cost to preparation plant operator to provide a ton of cleaned coal, when raw coal cost is
$7.00, differential cost is $5.04‡
$9.00, differential cost is $5.82‡
$11.00, differential cost is $6.60‡

3.0 Assessable benefit factors associated with clean coal

3.1 Added coal value per ton due to higher heat content of coal, when F.O.B. mine coal price is
$12.00, benefit is $2.46
$14.00, benefit is $2.89
$16.00, benefit is $3.30

3.2 Transportation cost saving due to increased heat content of the coal: $0.83/ton

3.3 Saving in ash disposal cost: $1.31/ton

3.4 Saving in grinding cost: $0.10/ton

3.5 Saving in benefit payment: $0.15/ton

3.6 Saving in maintenance: $0.33/ton

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*As-received values.

**Amortized over 15 years, 8% interest on unpaid balance.

†Based upon 260 days/year at 13 hours/day—3380 hours/year.

‡See pp. 45-46 of Ref. 3.

3.7 Total benefits per ton of coal cleaning when F.O.B. mine raw coal selling price is
$12.00, benefit is $5.18
$14.00, benefit is $5.61
$16.00, benefit is $6.02

4.0 Differential cleaning cost less benefits ($/ton)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	−0.14	−0.57	−0.98
9.00	0.64	0.21	−0.20
11.00	1.38	1.01	0.58

5.0 Stack gas cost factors
5.1 Boiler capacity: 500 MW
5.2 Utilization factor: 7000 hours/year
5.3 Tons of coal burned per year: 1 325 758
5.4 Minimum scrubber requirements
Scrubber ratings: 433 MW
Flue gas cleaned: 86.7%
5.5 Design scrubber requirements
Scrubber rating: 498 MW
Flue gas cleaned: 99.7%
5.6 Scrubber capital cost: $30 086 000
5.7 Scrubber capital charges per year: $4 678 000
5.8 Capital contribution per ton of coal: $3.53
5.9 Fuel and electricity cost per ton of coal: $0.76
5.10 O&M costs per ton of coal
Limestone: $0.72
Maintenance: $1.04
Fixation chemicals: $0.58
Oper. Labor: $0.12
Overhead: $0.88
5.11 Total stack gas cost per ton of coal burned: $7.63
5.12 Total stack gas cost per million Btu's consumed: $0.289
6.0 Cost per ton of coal burned to meet emission standards ($/ton)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	7.49	7.06	6.65
9.00	8.27	7.84	7.43
11.00	9.01	8.64	8.21

7.0 Cost per million Btu to meet emission standards ($/MMBtu)

Raw Coal Cost ($/Ton)	F.O.B. Mine Coal Selling Price ($/ton)		
	12.00	14.00	16.00
7.00	0.284	0.267	0.252
9.00	0.314	0.298	0.282
11.00	0.341	0.327	0.311

CASE C(A)-II

1.0 Case conditions: Sulfur cleanup exclusively by stack gas scrubbing

1.1-1.11 (Same as for Case C(A)-I)

2.0-4.0 (Not applicable)

5.0 Stack gas cost factors

5.1 Boiler capacity: 500 MW

5.2 Utilization factor: 7000 hours/year

5.3 Tons of coal burned per year: 1 671 442

5.4 Minimum scrubber requirements

Scrubber rating: 488 MW

Flue gas cleaned: 97.7%

5.5 Design scrubber requirements*

Scrubber rating: 500 MW

Flue gas cleaned: 100%

5.6 Scrubber capital cost: $33 429 000

5.7 Scrubber capital charges per year: $5 198 000

5.8 Capital contribution per ton of coal: $3.11

5.9 Fuel and electricity costs per ton of coal: $0.61

5.10 O&M costs per ton of coal

Limestone: $0.82

Maintenance: $0.92

Fixation chemicals: $0.67

Oper. labor: $0.11

Overhead: $0.87

5.11 Total cost per ton of coal burned to meet emission standards: $7.11

5.12 Total cost per million Btu consumed to meet emission standards: $0.340

*This scrubber must operate at design capacity at all times.

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